Standby Service to Distributed Generation Projects: The Wrong Tool for Subsidies

Providing subsidized standby service to DG is a mistake for two reasons. It is a shotgun approach to encouraging beneficial projects. Further, DG designers and operators will not plan and run their generating facilities efficiently if they do not face cost-based charges for standby service.

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I. Distributed Generation Is a Good Idea

Distributed generation (DG), as the term is generally used these days, has a number of key characteristics:

- It is located within the distribution network, often at the site of a major electricity consumer.
- It is usually, but not always, of smaller scale than most utility-owned or merchant generators.
- It may use a renewable energy source such as solar, wind, or landfill gas.
- It may be a combined heat and power (CHP) facility, also called a cogeneration facility, which produces useful steam or heat as well as electricity.
- It is generally not owned by the local utility.

DG projects vary widely in size, technology, fuel type, and location. The benefits they provide to their owners and to society in general are equally varied. DG produces energy that would otherwise have to be supplied by other generators. In jurisdictions with an effective wholesale electricity market, DG can increase competition in "load pockets" and reduce market power, thus putting downward pressure on market prices. DG has the potential to relieve congestion on

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the transmission system; because DG is located within the distribution network, DG energy often can be consumed without flowing over transmission lines. Depending on its size, operating pattern, and location, a DG project may relieve congestion on the subtransmission and distribution networks as well. Such congestion relief reduces line losses and generation costs, and improves reliability. DG with highly predictable energy production may even allow the utility to defer upgrades to its transmission and distribution systems, providing additional savings to consumers.

Some DG technologies may provide other benefits such as reduced air pollution. Of course these benefits may be offset by environmental damage; for example, wind projects may cause noise, visual pollution, and impacts on birds. Depending on technology, DG may increase fuel diversity for a region. Small-scale, scattered generators may be less susceptible to terrorism than large, central stations.

It is clear that DG can be beneficial to electricity consumers, to the environment, and to wholesale electricity markets. However, these benefits are highly dependent on the details of a given DG project: location, size, energy source, reliability, operating characteristics, etc. Some DG is very clean and efficient, but some technologies such as diesel sets are dirty and inefficient. Some potential DG locations will relieve grid congestion, while other locations such as remote wind sites will require new transmission facilities. Some DG will operate continuously, except for brief periods of maintenance, while some will operate only sporadically (e.g., when the wind blows) or be run only to shave peak or avoid periods of high market prices. Some technologies will be very reliable, while others may have high outage rates. Some DG projects will primarily supply on-site load, while others will be net exporters.

DG benefits are highly dependent on the details of a given project: location, size, energy source, etc.

II. DG Economics

The economic feasibility of a DG project depends upon many factors, including (1) the costs to the investor—initial equipment costs (plus upfront costs of permitting, interconnection with the utility grid, etc.), operating and maintenance costs (including standby electricity service), taxes, insurance; and (2) the benefits to the investor—price received for any net exports, avoided electricity purchases and avoided costs of producing heat or steam (for CHP projects).

DG projects provide electricity, but they also consume electricity. A project's electric bill is one of its operating costs. For example, a stand-alone project, i.e., one that is not associated with a particular consumer's load, needs electricity for start-up and "station use"—for lights, security, etc., when the generator is not operating. Another DG facility that normally serves all or a portion of a consumer's electricity needs must be backed up by a delivery system and alternative generation source to serve that load when the generator is not operating because of a planned maintenance outage, a forced outage, or a shut-down for economic reasons, and to supply supplemental power on a regular basis to make up for the difference between the customer's load and the DG's normal output. The level and structure of the rates for these standby services are, therefore, factors in the economics of the DG project.

DG economics are complicated by the fact that the costs and benefits to the investor are not always the same as the costs and benefits to society at large. For example, the benefits of reduced emissions and reduced transmission congestion are enjoyed by many people.

III. DG Incentives

As a result of the perceived discrepancy between the incentives for investors to pursue DG projects and the larger benefits of such projects to society, numerous subsidy schemes have been developed. These subsidies are designed to shift the business

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case in favor of the DG projects eligible for them. **Table 1** summarizes some of the available state and federal programs. Many of these incentive programs are targeted to reward investment in facilities that provide environmental benefits or to support emerging technologies. Others apply only to projects that provide site-specific savings to the utility. The incentive mechanisms include various tax breaks, grants and low-cost loans, payments per kWh produced, reduced connection charges, and net metering (which charges for energy delivered to the project and credits for energy delivered by the DG to the network at the standard retail rate). When the size of the incentive is related to the societal benefits provided by the project, these tools are appropriate for encouraging beneficial DG projects.

In some states there is pressure by DG manufacturers, promoters, and owners to provide an additional DG incentive in the form of subsidized standby electricity service. For example, in numerous hearings before the Los Angeles Department of Water and Power (LADWP) Board of Commissioners, DG promoters argued that DG projects would be hurt by proposed new DG rates that are based on the standard rates, but take into account different usage patterns by DG customers.[1] Many DG projects in Los Angeles are eligible for direct subsidies from the State, the South Coast Air Quality Management District, and LADWP. However,

Table 1: State and Federal Subsidies for Distributed Generation

	Tax Benefits	Grants	Loans	Payment per kWh	Net Metering
US	R	R&O	R	R	
AL				R	
AK			R&O		
AZ	R				R&O
AR					R
CA	R	R&O	R&O		R
CO			R	R	
CT	R	R			R&O
DE					R&O
DC					R&O
FL	R	R			R
GA				R	R
HI	R&O		O		R
ID	R		R		R&O
IL	R	R			R
IN	R	R&O			R
IA	R		R		R
KS	R	R			
KY				R	R
LA	R				
ME					R&O
MD	R	R			R
MA	R	R			R&O
MI		R&O			
MN	R	R	R	R	R&O
MS			R&O	R	
MO			R	O	
MT	R	R	R		R
NE			R		
NV	R				R
NH	R				R
NJ	R&O	R&O			R
NM	R				R&O
NY	R	R&O	R&O		R
NC	R		R	R	
ND	R				R&O
OH	R		R		R&O
OK	R				R&O
OR	R&O	R	R	R	R&O
PA		R&O	R&O	R	R&O
RI	R	R&O		R&O	R&O
SC					
SD	R				

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Table 1 *(Continued)*

	Tax Benefits	Grants	Loans	Payment per kWh	Net Metering
TN			R	R	
TX	R				R
UT	R				R&O
VT	R				R
VA	R			R	R
WA	R&O	R		R	R
WV	R				
WI	R	R	R		R&O
WY		R			R

R: Renewable Distributed Generation (i.e., solar, photovoltaics, wind, hydro, geothermal and fuel cells that use a renewable energy source). O: Other Distributed Generation.
Sources: The Database of State Incentives for Renewable Energy (DSIRE) at www.dsireusa.org (accessed on May 15, 2003).
"State Opportunities for State Action: Review of States' Combined Heat and Power Activities," ACEEE Research Report available at www.aceee.org.
The Green Power Network—Net Metering web site at http://www.eere.energy.gov/greenpower/netmetering/index.shtml#state.

the relatively low retail rates in Los Angeles hurt the economics of DG projects within the city compared to other parts of California served by investor-owned utilities.

Subsidization of rates for DG is also an issue in New York. The New York Public Service Commission (NYPSC) recently issued decisions on delivery standby rates[2] in several cases.[3] NYPSC guidelines for these rates provide that the rates be cost-based (which in the interim means derived from the standard retail rates), include the same markup for stranded cost recovery as non-DG rates, and have a different rate structure from current standard rates to reflect the DG customers' "intermittent and more random reliance on the delivery system." In particular, the costs of "local" distribution facilities are to be recovered by a contract demand charge, rather than based on usage in a given month. The NYPSC was very clear that standby rates should not be used as a subsidy mechanism:

> [The Guidelines] do not include extraneous factors sought by various parties, such as public policy values or benefits to utilities from DG, which in our view do not belong in the development of standby delivery rates. Rather, such factors should be considered and applied, if appropriate, in the context of a utility's distribution planning process.[4]

In very contentious proceedings, intervenors requested provisions that would reduce standby rates below those developed by the utilities following the NYPSC guidelines. For example, the Case Energy Project (of Case University Law School), representing DG interests, proposed allowing renewable and efficient CHP DG to choose the lower of the standby rate or the standard rate, and allowing the utilities to recover the lost revenue from other customers:

> Pace recommends that the Commission adopt this simple approach, which eliminates the harm that would otherwise be caused by application of the Con Edison standby tariff. Pace provides an option for Con Edison to propose and implement, subject to Commission approval, a lost revenue recovery mechanism.[5]

In July of this year the NYPSC approved a compromise. The Orders in these cases[6] set efficient, cost-based standby rates, but provided phase-in periods for existing DG projects that would otherwise see higher bills from the new rates. New small, efficient CHP projects and new projects using certain technologies deemed to provide social benefits have a choice of accepting a five-year phase-in (starting in 2004) of the new standby rates or (offered until 2006) continuing to pay for standby service on the standard (non-cost-based) rates.

In the May 2003 issue of *The Electricity Journal*, Sean Casten argued that standby rates, which he defined as rates that include "a flat monthly charge for potential, rather than actual, power provided," are "not only unnecessary, but they actually stand in direct opposition to the public interest."[7] His basic arguments are that (1) DG provides societal benefits and, therefore, any action, such as imposition of standby rates, which has adverse impacts on DG economics should

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be avoided; and (2) a utility does not have to stand by for the full nameplate capacity of a DG project because of diversity. This second point is true only for generation, and perhaps transmission, although Casten does not make this distinction.[8]

Contrary to the positions of these DG proponents, providing subsidized standby service to DG is a mistake. First, as explained above, it should not be assumed that all DG brings external social benefits. Subsidized standby service is a shotgun approach to encouraging beneficial projects. In fact, since projects that operate only sporadically require the most standby service, it gives the largest subsidies to the least desirable projects. Second, DG designers and operators will not plan and run their generating facilities efficiently if they do not face cost-based charges for standby service. For example, if standby rates include only a per-kWh charge levied on kWh used each month, DG designers will have no incentive to minimize spikes in their standby use or to economize on the size of the transformer they request to serve them. If those per-kWh charges are not time-differentiated, DG operators will have no incentive to schedule their maintenance in periods when system costs are low. Finally, manipulating standby rates to benefit DG constitutes a hidden tax on other consumers. In a democracy, subsidization of socially beneficial endeavors should be done openly, so that voters are aware of the subsidy decisions their elected representatives are making on the voters' behalf. When subsidies are buried in obscure rate designs, this transparency goal is thwarted.

IV. Good DG Rate Design

Customers with DG may have load characteristics that are very different from those of customers that purchase all of their electricity requirements. This is why traditional rate structures designed for customers without generation do not work well for standby service. Furthermore, the wide variations in operating characteristics of DG installations using different technologies and fuel types and with different purposes mean that DG customers are a very heterogeneous class of customers. A residential customer with solar panels on the roof has consumption characteristics very different from those of a commercial customer using CHP for HVAC and water heating, or a small business with a microturbine used for peak shaving.

In most places the structure of full service rates does not fully reflect the cost structure of electricity service.

If standard rates were designed to recognize wide discrepancies in usage patterns, there would be no need for separate DG rates. However, in most places the structure of full service rates does not fully reflect the cost structure of electricity service.[9] For example, most utility rates for small customers recover delivery costs that do not vary with energy consumption in the per-kWh charges; the fixed components of these rates are too low and the usage-sensitive components are too high. Such distortions are inefficient, but not inequitable if the class is fairly homogeneous. Allowing DG customers to purchase standby service on such standard rates would significantly undercharge them; they use too few kWh to pay for the fixed distribution costs of serving them.

What is the optimal cost-based structure for electricity rates? Generation costs (both energy and capacity) are a function of a customer's energy use in a given hour and should ideally be recovered in highly time-differentiated charges per kWh. In a region with a flourishing wholesale electricity market, these costs are market prices, which can vary by hour. If time-of-use metering is not cost-effective, capacity costs can be converted to a demand charge, but this is a second-best rate structure.[10] The transmission element of electricity service is a function of the customer's use in

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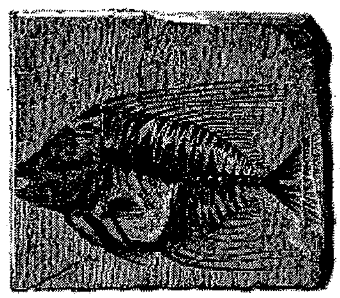
hours when the transmission system is strained (or in hours that trigger transmission payments by the delivery company or retailer in cases where transmission is provided by a retail transmission organization (RTO) or independent transmission provider (ITP)). A portion of transmission cost is included in locational market prices if such a system is part of the regional market design. Again, highly time-differentiated charges per kWh are the best way to recover these costs in rates. Distribution costs consist of the costs of hooking an individual customer to the distribution network (meter and service drop), costs of shared facilities sized based on customers' maximum expected loads over the life of the facilities (secondary lines, transformers, local primary lines), and costs of local facilities shared by many more customers and sized based on anticipated near-term peak loading by all customers using them (trunk primary lines and distribution substations). The hook-up costs are per-customer costs, the shared local facilities costs are costs per kW of expected peak demand or contract capacity, and the trunkline/substation costs vary with energy use in the critical peak load hours on those facilities. Finally, there are per-customer costs associated with meter reading, billing, customer accounting, and customer information services.

Cost-based rates for DG (and any customer group) should ideally consist of a fixed customer charge to recover hook-up costs and customer-related expenses, a facilities charge levied per kW of expected maximum load (or contract capacity), and time-differentiated per-kWh charges that cover the time-varying costs of generation, transmission, and trunkline/distribution substations. There is an important exception with regard to the



trunkline/substation costs in the cases where (1) a single DG facility (or other large customer with intermittent load) constitutes a significant part of the load on these facilities and (2) a group of DG facilities with the same technology (e.g., wind) or fuel (e.g., gas) together constitute a significant share of the load on these facilities and may all be shut down simultaneously. In these cases, to provide reliable service to all customers served by the facilities, the trunkline and substation have to be sized to handle the sum of the full potential load of the DG plus the coincident peak of full-service customers.[11] As a result, the DG (and other large intermittent) customers should pay for this component on a fixed, per-kW-of-contract-capacity basis rather than on a usage basis.

In cases where strandable generation costs are being recovered in bundled rates or delivery charges, and where marginal costs must be marked up to match the delivery revenue requirement, individual rate elements deviate from cost. For the sake of fairness, and to avoid giving DG an unintended subsidy, DG rates should include a comparable markup. If DG customers were excused from making a contribution to stranded generation costs, DG projects that would otherwise not be cost-effective (and not provide benefits at least as large as the revenues shifted to other consumers) might be built.

California requires new DG (other than small, net-metered facilities) to pay for generation costs incurred as a result of the California market meltdown on the basis of cents per kWh produced. There are exemptions (and partial exemptions) from surcharges for certain new clean and ultra-clean facilities.[12] New York's standby service pricing guidelines require that DG delivery rates contain the same percentage mark-up for stranded cost recovery as rates for otherwise applicable service.[13]

With the optimal rate design in place for all classes, DG customers could be charged under the same rates as full-service customers. In months when a DG customer self-supplied all its energy needs, it

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would pay only the customer and distribution facilities charges—fully compensating the utility for standing by with local distribution equipment, metering, billing systems, call center, etc. In months when the DG unit was not operating fully, or on a regular basis to supply load in addition to the normal capability of the DG unit, the DG customer would also pay the time-differentiated usage charges.

Congress and the Federal Energy Regulatory Commission (FERC) addressed these same issues in the context of standby rates for Qualifying Facilities (QFs) over 20 years ago. Section 210 of the Public Utilities Regulatory Policies Act of 1978 required FERC to establish rules for utility sales of electricity to qualifying cogenerators and small power producers. The rates charged were to be just, reasonable, and in the public interest, and to not discriminate against the QFs.[14] FERC's regulations implementing PURPA provided guidance on what constituted non-discriminatory rates. "Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics."[15] The rules also required that rates for maintenance and standby power not be based on the assumption that all QFs would need these services simultaneously or at the time of the system peak (unless supported by factual data).[16]

Subsidization of standby rates for DG projects is the wrong tool for encouraging socially useful DG development.

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Although one of the key goals of PURPA was to support the development of small, efficient, non-utility generation, there was no suggestion that QFs should be subsidized through the mechanism of below-cost rates for backup, maintenance and supplemental electricity services.

V. Summary and Conclusions

DG has the potential to provide important benefits for a utility's consumers and for society at large. However, the benefits are extremely project-specific. Incentives for DG development should be targeted and tied to the specific benefits provided. Not every potential DG project deserves to be built.

Subsidization of standby rates for DG projects is the wrong tool for encouraging socially useful DG development. Distorting standby rates to provide DG subsidies is a shotgun approach that will encourage both good and bad projects, give uneconomic signals for the design of such projects, and lead to inefficient use of standby service.

Standby rates for DG should be judged not on the basis of whether they encourage DG development, but rather on whether they reflect the cost of providing service to the DG project (plus a fair contribution to any above-market costs that other customers are paying). These rates should recover in fixed charges the costs of the local network required to stand by to serve intermittent DG loads, and recover in (ideally time-differentiated) usage charges per kWh costs that vary with electricity delivered to the project.■

Endnotes:

1. The proposed rates, as of this writing, have not yet been approved by the

City Council. The current DG rates contain an inadvertent subsidy that causes large bill reductions for subtransmission customers that install a very small DG unit, and overcharges DG projects connected at primary voltage. [LADWP Approval Board Letter, Sept. 16, 2002, Amendment of Electric Rate Ordinance No. 168436, Customer Generation.]

2. New York has retail competition and generation charges to DG customers purchasing generation service from the utility are the same as those applying to customers without generation.

3. Cases 02-E-0780/-0781 Con Edison and Orange and Rockland Standby Service; Case 02-E-0551 Rochester Gas & Electric Standby Rates; Case 02-E-0779 New York States Electric & Gas Corporation.

4. NYPSC Opinion No. 01-4, Opinion and Order Approving Guidelines for the Design of Standby Service Rates, Oct. 26, 2001, at 27.

5. Pace Energy Project's Initial Statement in NYPSC Case 02-E-0781—Consolidated Edison Company of New York, Inc.—Standby Electric Rates, March 11, 2003.

6. See, for example, "Order Establishing Electric Standby Rates," NYPSC Cases 02-E-0780 and 0781, July 29, 2003.

7. Sean Casten, *Are Standby Rates Ever Justified? The Case Against Electric Utility Standby Charges as a Response to On-Site Generation*, ELEC. J., May 2003, at 58–65.

8. He does seem to acknowledge that the diversity argument does not hold for local distribution facilities: "As one moves 'closer' to the customer, peaks become more coincident, the diversity of DG served by a given component falls, and the utility asset utilization is increasingly dependent upon that customer." (p. 64).

9. It is the *marginal* cost of service that is of importance in the design of rates so that customers have price signals to invest in equipment and consumer electricity efficiently.

10. The customer's peak demand in a given month is a poor proxy for the customer's consumption in high-cost hours in the month. Furthermore, once the customer has hit what it expects to be its peak for the month, it has little incentive to control its demand; incremental demand in other hours is free.

11. In this context, "coincident peak" means the highest combined load of the customers using the facilities.

12. CPUC Decision 03-04-030, Opinion on Cost Responsibility Surcharge Mechanisms for Customer Generation Departing Load, April 3, 2003.

13. NYPSC Opinion No. 01-4, "Opinion and Order Approving Guidelines for the Design of Standby Service Rates," Oct. 26, 2001, at 6.

14. Public Utility Regulatory Policies Act of 1978, Section 210(c).

15. FERC Order 69, 18 CFR 292.305(a)(2).

16. *Id.*, Part 202.305(c).

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Letters to the Editor

Standby Rates Issue Is More Nuanced Than Authors Let on

The exchange in the October issue of the *Journal* by Jay Morrison and Sean Casten on standby rates for distributed generators (DG) reminded me of many of the "discussions" I have had with my husband of 32 years—both are right, at least to some extent.

- In his article, "Why We Need Standby Rates for On-Site Generation," Morrison says that some DG technologies have the potential to go out simultaneously (wind power projects when the wind doesn't blow, gas-fired units when the price of gas is high). In his rebuttal, "How Far We Have to Go," Casten says there can be situations when this is not true (wind blows in some areas and not in others).
- Morrison says that some DG is dirtier and less efficient than central station generators. Casten says that some DG is cleaner and more efficient.

These statements, all true, highlight a major point in my own article that month, "Standby Service to Distributed Generation Projects: The Wrong Tool for Subsidies," as well as Morrison's: that the costs and benefits of DG are project-specific, and that subsidizing all DG by underpricing standby service is not the way to ensure that the good projects are built and the bad projects die on the drawing board.

But the two authors are not always right. On the issue of the level of reserves necessary to provide standby service to DG, both authors fall into the trap of failing to distinguish adequately the very different effects of DG on generation and high-voltage transmission from their effects on local delivery facilities. Morrison's introductory paragraph characterizes Casten's earlier article on this subject (in the May 2003 issue of the *Journal*) as reflecting a fundamental misunderstanding of the impact of DG on *distribution facilities*. However, much of Morrison's discussion lumps generation and transmission in with distribution. He claims that there are only a few circumstances under which a utility need not design its system to meet a consumer's maximum demand. While I would agree that this is generally true for the *distribution* system (and Morrison makes this case very well), it is not true for high-voltage transmission and generation because of the diversity of demands by the customers using these systems. Casten makes the opposite mistake, claiming that DG diversity means that distribution, as well as generation and transmission, can be sized assuming that DG standby loads are unlikely to occur when facilities are heavily utilized by other customers.

Morrison's description of standby rate development suggests that standby rates are designed to collect from consumers with generators the same share of the system's fixed costs that they would have paid had they not installed on-site generation. He justifies this approach with the statement that the generation and infrastructure capacity must be available on the system in the event that a DG unit fails, or other consumers may experience outages.

Not all utilities' standby rates charge for generation, transmission, and distribution capacity as though the customer had never

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installed DG. Furthermore, Casten is correct that doing so overcharges DG for high-voltage transmission and generation costs and artificially inflates the cost of DG. Even a traditional, vertically integrated utility would not assume that all of the DG on its system would be out simultaneously for purposes of planning *generation and transmission*. And in a competitive wholesale market, an LSE should be able to purchase generation and transmission in the spot market to serve unpredictable DG loads or, if the LSE owns the necessary generation and transmission capacity, sell unused capacity in the spot market when the DG doesn't need it. In either case, the annual cost of providing generation and transmission capacity for a kW of standby load is likely to be lower than the annual cost for a kW of load imposed by a customer without DG.

Casten criticizes the utility and regulatory mentality that gives rise to standby rates. He suggests that utilities are misguided to look at standby customers as causing costs that need to be recovered in new rates. He thinks the utilities should attract customers for the revenue that they represent, and accept the cost of those customers as an investment to be recouped. Unfortunately, regulated utilities, unlike Casten's company, do not have the luxury of going after customers that are profitable and turning down the rest. They have to serve[1] whatever customer comes along. If the resulting costs are not recovered from that customer, they are shifted—at first to the utility's shareholders and ultimately to the utility's other customers. To the extent that a particular DG customer provides benefits to the system or to society in general, the utility (or the government) may find it appropriate to offer incentives.

But the efficient form of incentives, as Morrison and I point out, is not subsidized standby service.

Casten ridicules Morrison's observation that typical rate structures are not designed to accommodate standby service,[2] and suggests that no business designs rates for non-customers. Casten is being a little too clever. Standby customers are not "non-customers." They are customers whose service has very different characteristics from that provided to customers without generation. Without the type of overhaul of rate structures for full-service customers described by Morrison and by me, standby service will require a separate rate to avoid cross subsidies. As I explain in my own article, that rate should charge customers every month for local facilities that have to be sized to handle full DG standby loads, but should charge for generation and other elements of delivery only when the DG customer actually uses these components of the system.

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Endnotes:

1. Either delivery service only or combined delivery and generation service, depending on the status of retail competition in the state and the customer's preference.

2. I made a similar comment in my article.

The Wrong Read On Aerosol Forcing

In your News in Focus section in July 2003, your item headlined "Two Studies Cast Doubt on the IPCC Conclusions" distorts the content of the May 16 *Science* article "Climate Forcing by Aerosols: A Hazy Picture" by T.L. Anderson, *et al*. The story quotes the primary author as stating "and so projections of future climate change might be in error as well." It ends by quoting co-author Robert Charlson as saying, "We can expect surprises and breakthroughs in quantifying aerosol forcing, but